Electricity Report

AUSTRALIAN ENERGY REGULATOR

23 - 29 September 2018

Introduction

The AER is required to publish the reasons for significant variations between forecast and actual price and is responsible for monitoring activity and behaviour in the National Electricity Market. The Electricity Report forms an important part of this work. The report contains information on significant price variations, movements in the contract market, together with analysis of spot market outcomes and rebidding behaviour. By monitoring activity in these markets, the AER is able to keep up to date with market conditions and identify compliance issues.

Spot market prices

Figure 1 shows the spot prices that occurred in each region during the week 23 - 29 September 2018.

Figure 1: Spot price by region ($/MWh)

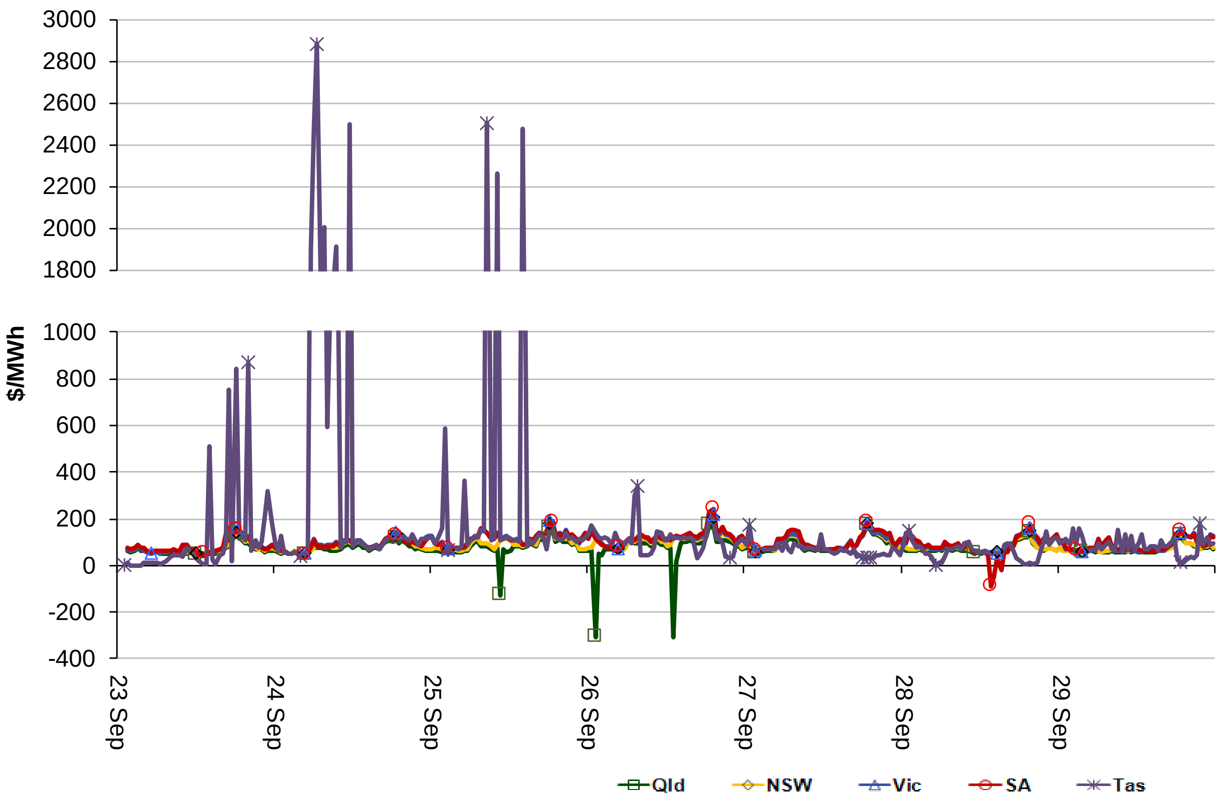


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

Figure 2: Volume weighted average spot price by region ($/MWh)

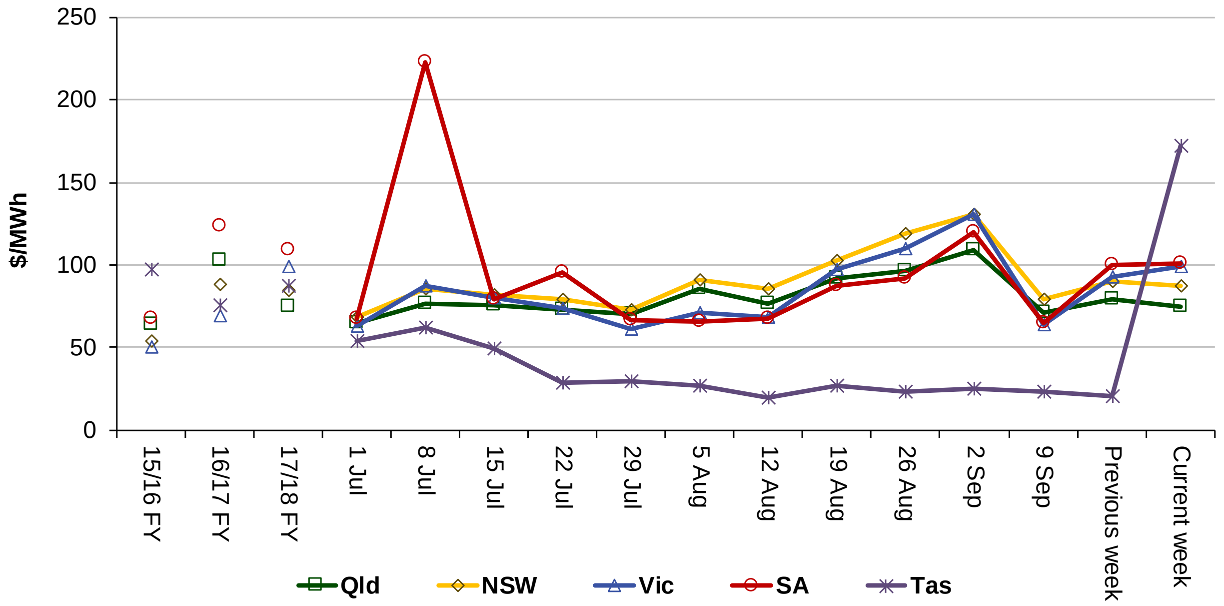


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	75	87	99	101	172
17-18 financial YTD	82	96	104	103	98
18-19 financial YTD	80	90	84	95	43

Longer-term statistics tracking average spot market prices are available on the AER website.

Spot market price forecast variations

The AER is required under the National Electricity Rules to determine whether there is a significant variation between the forecast spot price published by the Australian Energy Market Operator (AEMO) and the actual spot price and, if there is a variation, state why the AER considers the significant price variation occurred. It is not unusual for there to be significant variations as demand forecasts vary and participants react to changing market conditions. A key focus is whether the actual price differs significantly from the forecast price either four or 12 hours ahead. These timeframes have been chosen as indicative of the time frames within which different technology types may be able to commit (intermediate plant within four hours and slow start plant within 12 hours).

There were 259 trading intervals throughout the week where actual prices varied significantly from forecasts. This compares to the weekly average in 2017 of 185 counts and the average in 2016 of 273. Reasons for the variations for this week are summarised in Table 2. Based on AER analysis, the table summarises (as a percentage) the number of times when the actual price differs significantly from the forecast price four or 12 hours ahead and the major reason for that variation. The reasons are classified as availability (which means that there is a change in the total quantity or price offered for generation), demand forecast inaccuracy, changes to network capability or as a combination of factors (when there is not one dominant reason). An instance where both four and 12 hour ahead forecasts differ significantly from the actual price will be counted as two variations.

Table 2: Reasons for variations between forecast and actual prices

	Availability	Demand	Network	Combination
% of total above forecast	6	12	0	6
% of total below forecast	19	48	0	9

Note: Due to rounding, the total may not be 100 per cent.

Generation and bidding patterns

The AER reviews generator bidding as part of its market monitoring to better understand the drivers behind price variations. Figure 3 to Figure 7 show the total generation dispatched and the amounts of capacity offered within certain price bands for each 30 minute trading interval in each region.

Figure 3: Queensland generation and bidding patterns

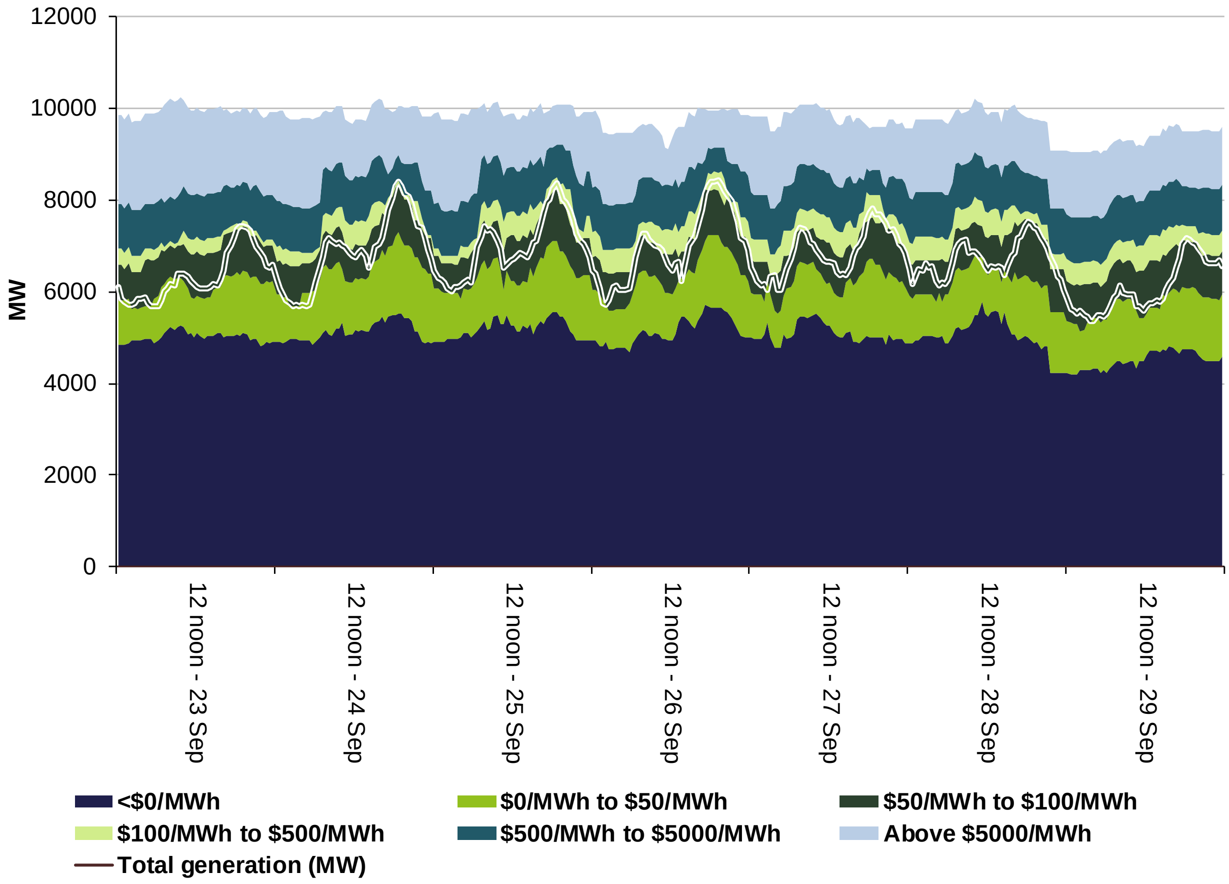


Figure 4: New South Wales generation and bidding patterns

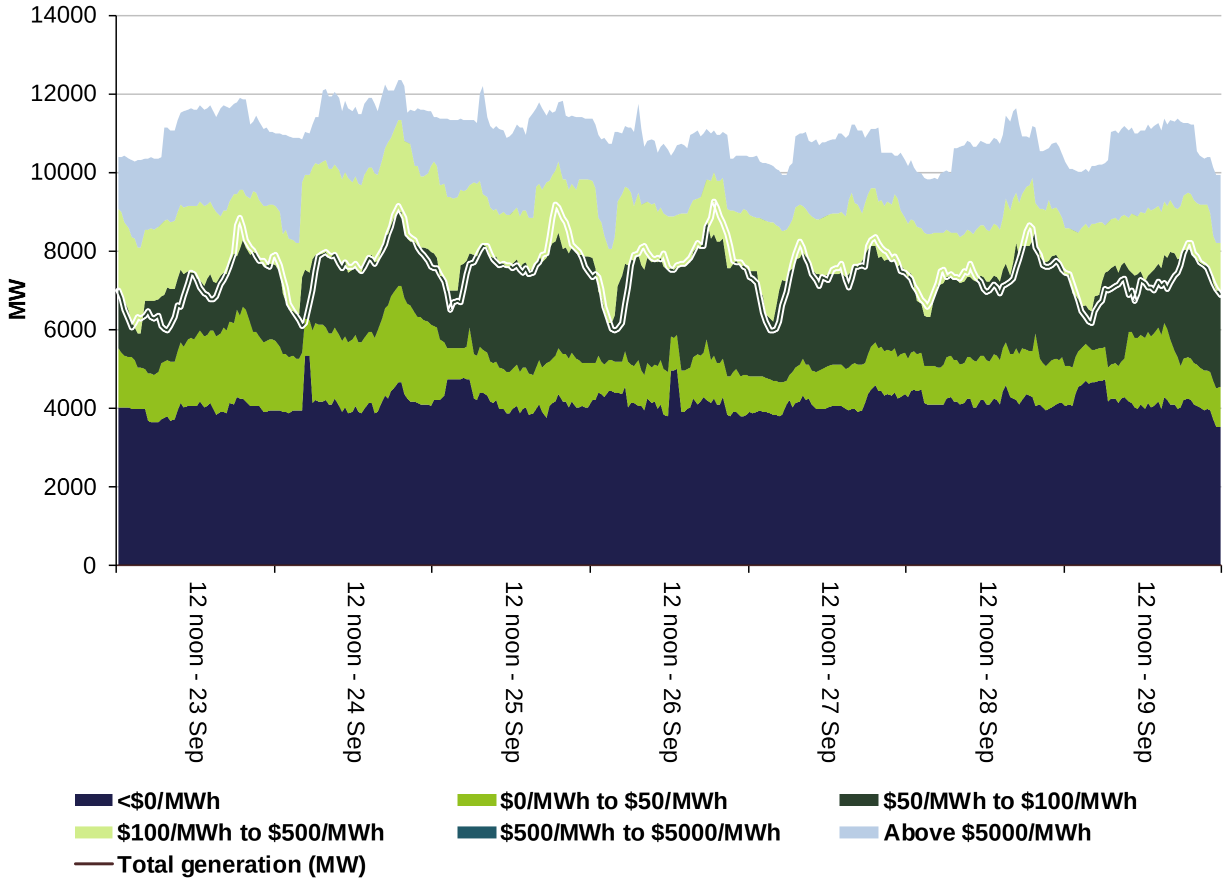


Figure 5: Victoria generation and bidding patterns

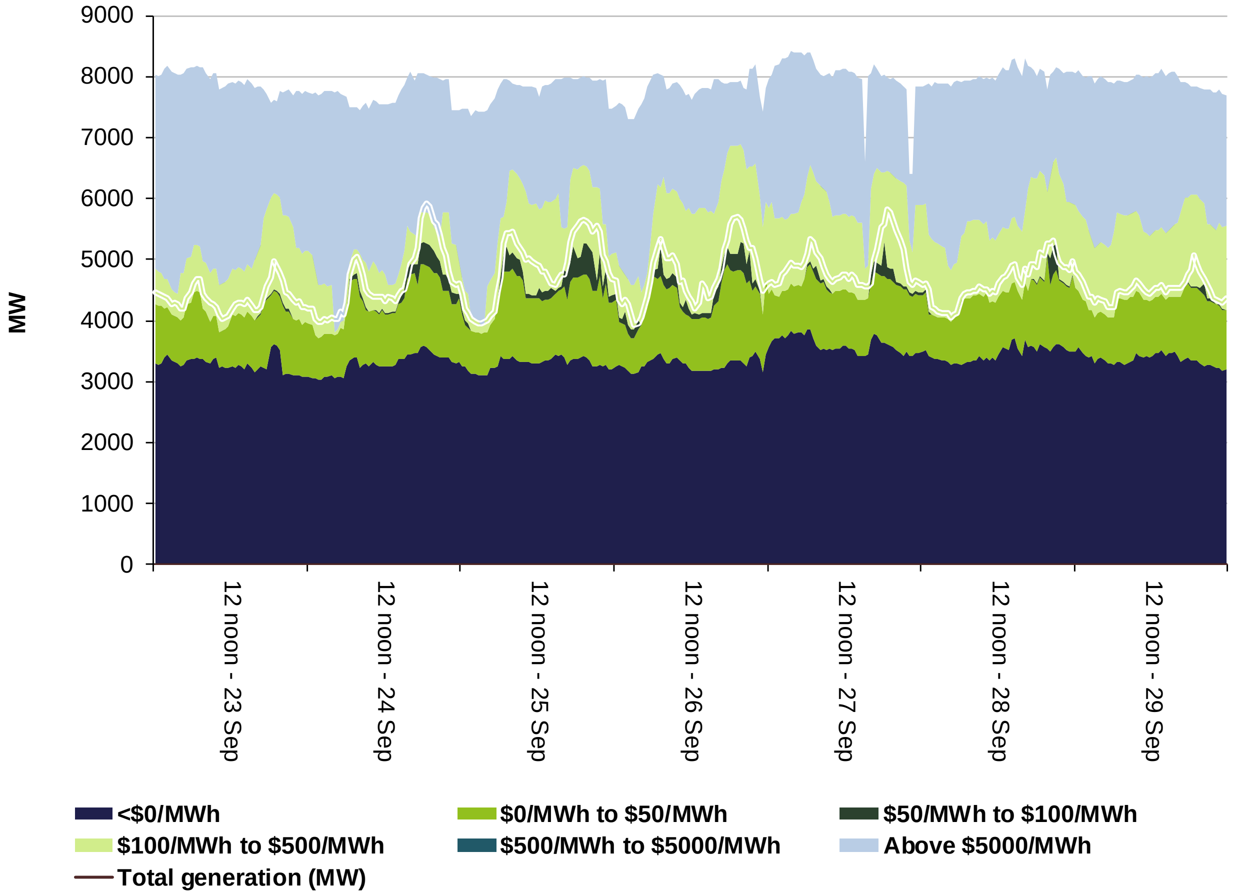


Figure 6: South Australia generation and bidding patterns

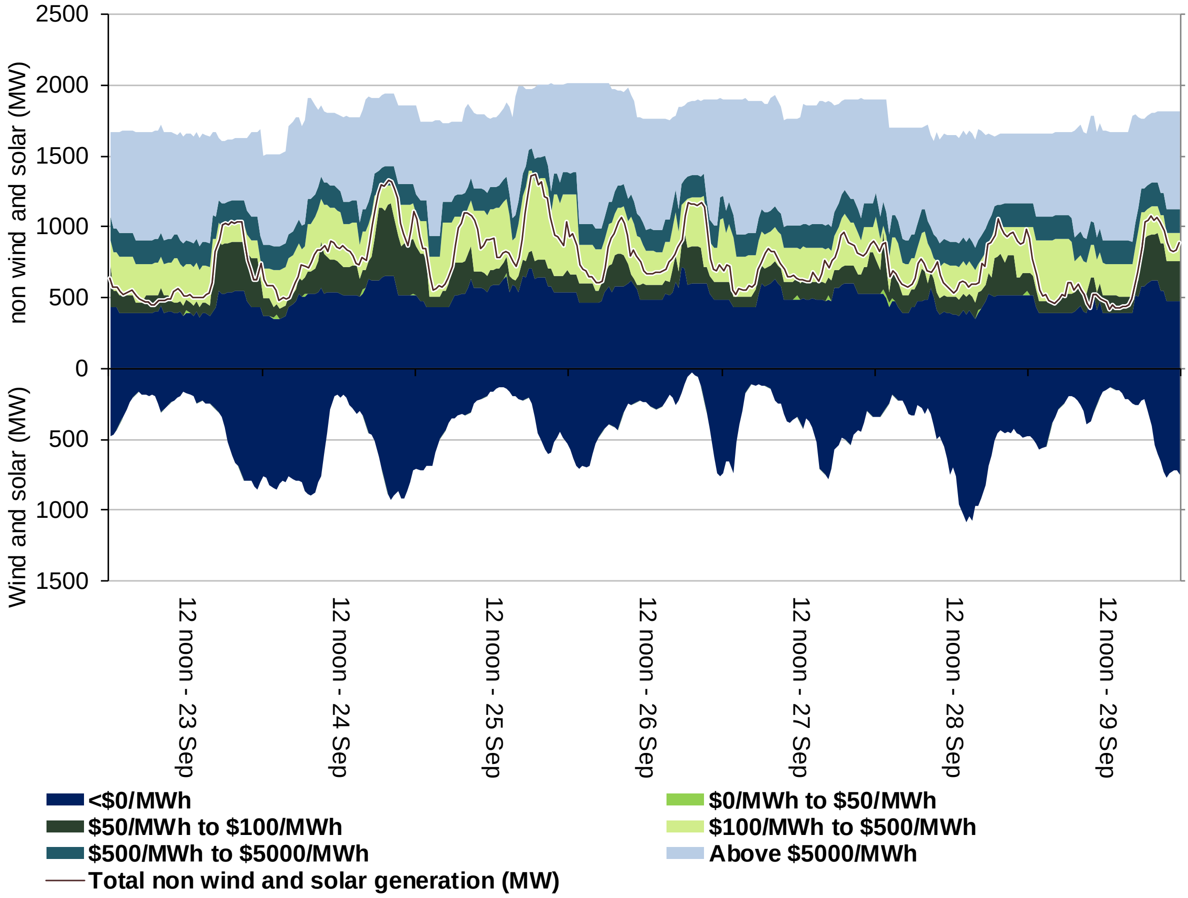
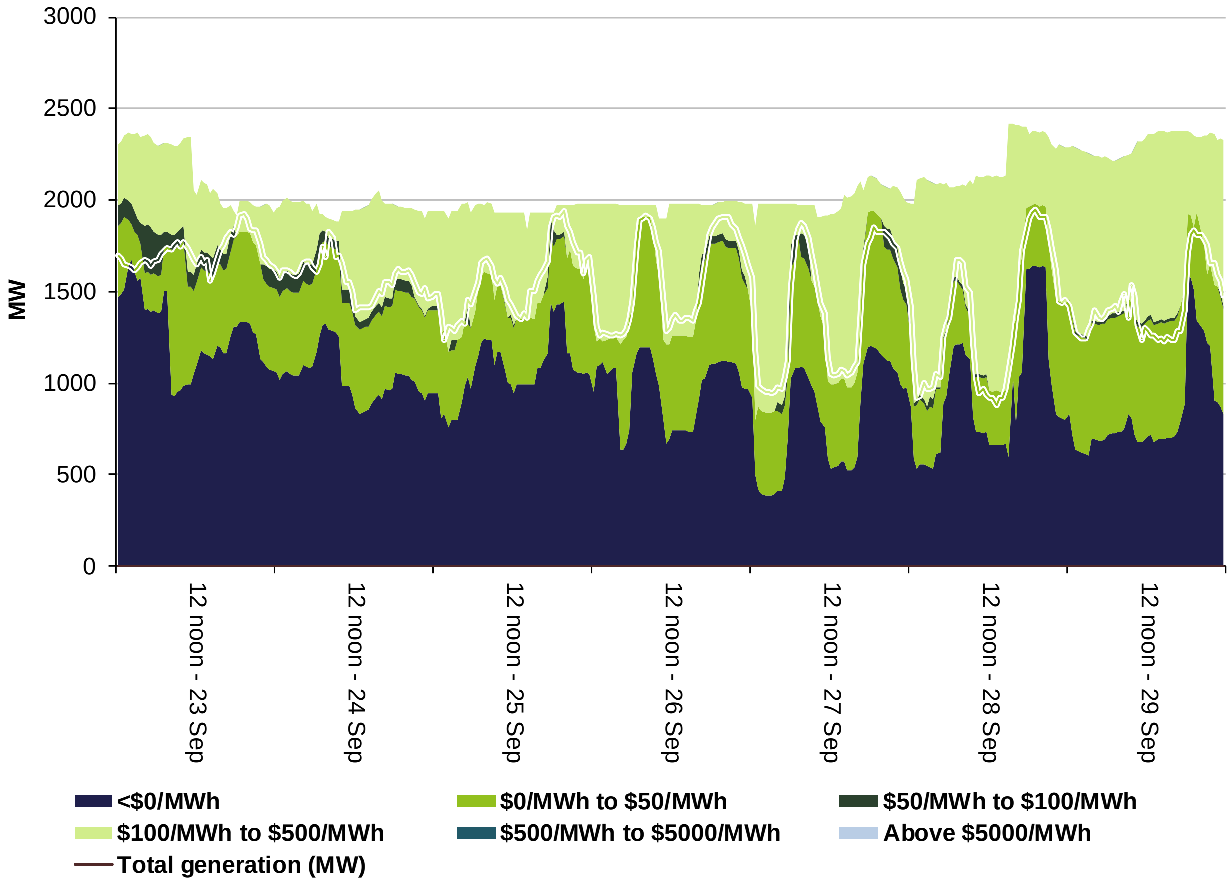


Figure 7: Tasmania generation and bidding patterns



Frequency control ancillary services markets

Frequency control ancillary services (FCAS) are required to maintain the frequency of the power system within the frequency operating standards. Raise and lower regulation services are used to address small fluctuations in frequency, while raise and lower contingency services are used to address larger frequency deviations. There are six contingency services:

- fast services, which arrest a frequency deviation within the first 6 seconds of a contingent event (raise and lower 6 second)
- slow services, which stabilise frequency deviations within 60 seconds of the event (raise and lower 60 second)
- delayed services, which return the frequency to the normal operating band within 5 minutes (raise and lower 5 minute) at which time the five minute dispatch process will take effect.

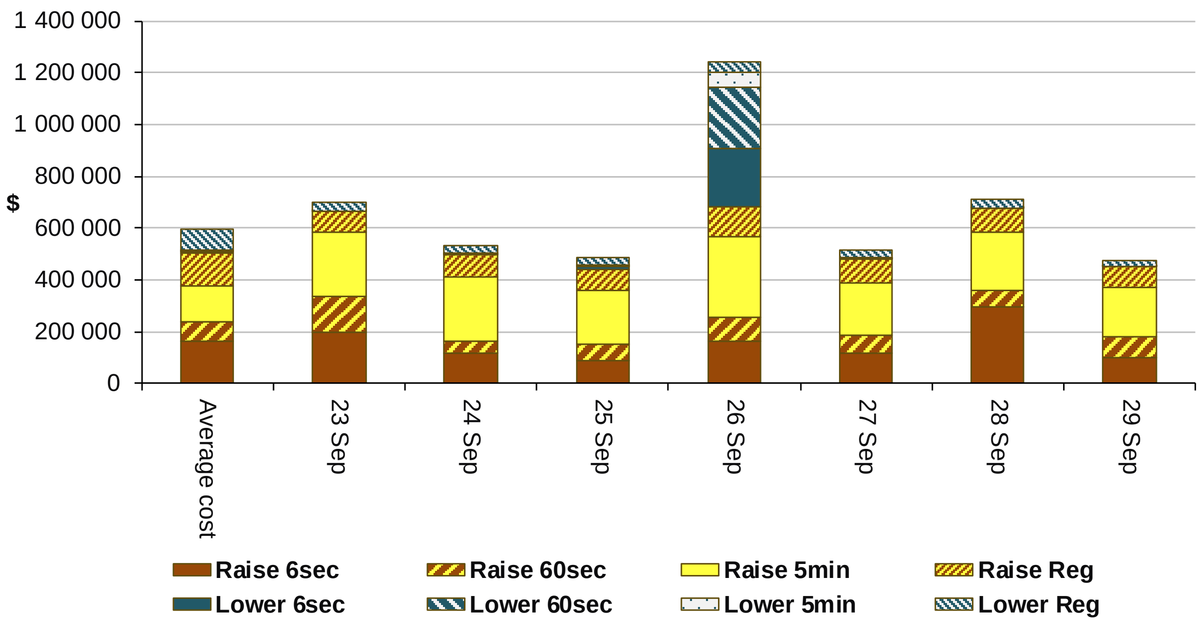
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a “causer pays” basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $3 973 500 or around one per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $689 500 or around two per cent of energy turnover in Tasmania.

Figure 8 shows the daily breakdown of cost for each FCAS for the NEM, as well as the average cost since the beginning of the previous financial year.

Figure 8: Daily frequency control ancillary service cost



The higher than average costs for lower services on 26 September was a result of AEMO reclassifying the loss of the Bulli Creek to Dumaresq 330 kV lines as a credible contingency in Queensland. When the line was reclassified (at around 1 am and 1.10 pm), there were an increase in local lower requirements, leading to the higher costs on the day.

Detailed market analysis of significant price events

Queensland

There was three occasions where the spot price in Queensland was below -$100/MWh.

Tuesday, 25 September

Table 3: Price, Demand and Availability

Time	Price ($/MWh)			Demand (MW)			Availability (MW)		
	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast
11 am	-129.85	75.71	73.52	5836	5742	5681	9822	9897	9974

Demand was around 100 MW greater than forecast and availability was close to forecast, both four hours ahead.

Due to lightning, at around 10.30 am AEMO reclassified the loss of the Bulli Creek to Dumaresq 330 kV lines as a credible contingency. At 10.35 am, constraints invoked to manage the contingency reduced exports into New South Wales across the QNI interconnector by 490 MW. The sudden drop in exports meant even though more expensive generation was dispatched, it was either ramp constrained or trapped in FCAS and could not set price. The dispatch price fell to -$1000/MWh for one dispatch interval and led to the negative spot price.

Wednesday, 26 September

Table 4: Price, Demand and Availability

Time	Price ($/MWh)			Demand (MW)			Availability (MW)		
	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast
1.30 am	-308.31	60.73	64.78	5257	5296	5259	9757	9767	9787
1.30 pm	-307.43	92.31	74.21	5761	5781	5751	9617	9655	9779

For both trading intervals, demand and availability were close to forecast, four hours prior.

Due to lightning, at around 1 am AEMO reclassified the loss of the Bulli Creek to Dumaresq 330 kV lines as a credible contingency. At 1.10 am, constraints invoked to manage the contingency reduced exports into New South Wales across the QNI interconnector by 435 MW. The sudden drop in exports meant even though more expensive generation was dispatched, it was either ramp constrained or trapped in FCAS so could not set price. The price was co-optimised with the FCAS markets and set at the floor. The price fell to the floor again at 1.20 am when exports fell by 80 MW and local wind generation increased by 60 MW. Again, even though more expensive generation was dispatched, it was either ramp constrained or trapped in FCAS so could not set price.

Similarly for the 1.30 pm trading interval, the dispatch price fell to the floor twice during the trading interval.

At 12.33 pm Stanwell added 105 MW of capacity priced at the floor at Stanwell power station, the reason related to needing a fixed load.

At around 1.10 pm AEMO again reclassified the loss of the lines as a credible contingency. At 1.20 pm, constraints invoked to manage the contingency reduced exports into

New South Wales across the QNI interconnector by 431 MW. The sudden drop in exports meant even though more expensive generation was dispatched it was ramp constrained and could not set price. The price stayed at the floor for the 1.25 pm dispatch interval because demand fell by 95 MW and exports reduced further by 27 MW. Although more expensive generation was again dispatched, it was either ramp constrained or trapped in FCAS so could not set price.

Tasmania

There were 17 occasions where the spot price in Tasmania was greater than three times the Tasmania weekly average price of $172/MWh and above $250/MWh.

Sunday, 23 September

Table 5: Price, Demand and Availability

Time	Price ($/MWh)			Demand (MW)			Availability (MW)		
	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast
5.30 pm	755.65	81.14	269.88	1288	1253	1260	1969	2002	1977
6.30 pm	845.50	269.92	81.99	1362	1343	1353	1953	2016	1986
8.30 pm	869.56	21.92	269.88	1373	1336	1352	1986	1992	1997

Conditions at the time saw demand and availability close to forecast. The high price events that occurred between 23 and 25 September will be discussed here.

There was a 16 day outage of the Palmerston to Sheffield 220 kV line (from 19 September – 4 October 2018). The constraint used to manage the outage limits generation from 10 generators located in northern Tasmania. Exports across Basslink help to relax the constraint (higher exports mean greater capacity for the generating units in the constraint).

Across all three days of higher than forecast prices all capacity in Tasmania was offered at prices less than $500/MWh.

All of the trading intervals that breeched our threshold contain at least one dispatch interval where the constraint managing the line outage bound or violated, limiting local generation and as a result reducing exports to Victoria. When this occurred other generation in southern Tasmania was often ramp limited, trapped or stranded in FCAS so could not set price. At these times the price was set by either co-optimisation of the energy and FCAS markets or a number of generators, resulting in 24 dispatch prices between $1000/MWh and the price cap across the three days. These volatile dispatch prices led to the higher than forecast spot prices.

Monday, 24 September

Table 6: Price, Demand and Availability

Time	Price ($/MWh)			Demand (MW)			Availability (MW)		
	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast
6 am	1901.77	81.14	59.24	1197	1204	1222	1954	1974	1968
6.30 am	2482.09	269.88	72.86	1232	1292	1307	1979	1975	1967

Time	Price ($/MWh)			Demand (MW)			Availability (MW)		
	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast
7 am	2884.72	269.92	269.88	1312	1380	1388	1943	1971	1966
7.30 am	1567.69	190.30	269.75	1338	1460	1459	1972	1969	1964
8 am	2003.92	5424.87	145.11	1350	1478	1492	1925	1927	1921
8.30 am	591.53	321.46	269.92	1354	1478	1478	1901	1925	1920
9 am	1126.98	214.59	115.15	1331	1433	1449	1924	1925	1918
9.30 am	1726.69	213.24	269.77	1279	1395	1403	1904	1921	1917
10 am	1916.22	246.67	81.03	1254	1353	1365	1880	1921	1917
Midday	2501.16	45.21	82.37	1188	1172	1248	1942	1929	1923

Please see discussion under Table 5.

Tuesday, 25 September

Table 7: Price, Demand and Availability

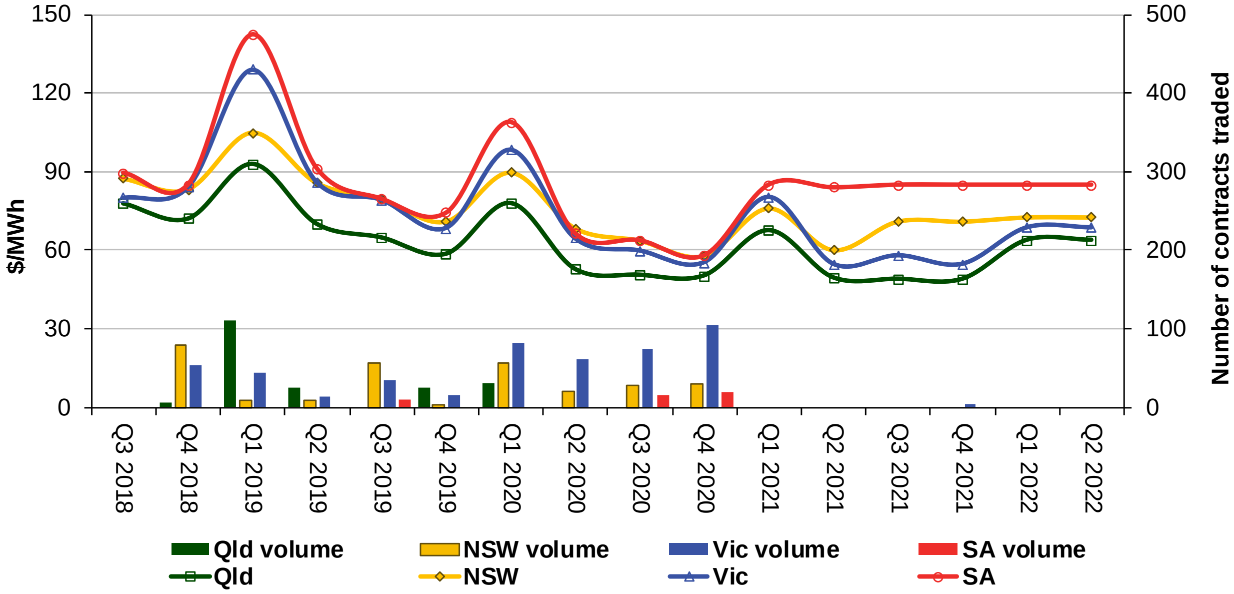
Time	Price ($/MWh)			Demand (MW)			Availability (MW)		
	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast
2.30 am	584.74	269.75	71.60	1041	1078	1109	1933	1945	1956
9 am	2509.05	138.38	269.79	1353	1407	1411	1979	1987	1994
10.30 am	2266.33	117.86	269.65	1262	1283	1312	1932	1993	1991
2.30 pm	2480.41	100.77	269.49	1039	1145	1221	1884	1947	1994

Please see discussion under Table 5.

Financial markets

Figure 9 shows for all mainland regions the prices for base contracts (and total traded quantities for the week) for each quarter for the next four financial years.

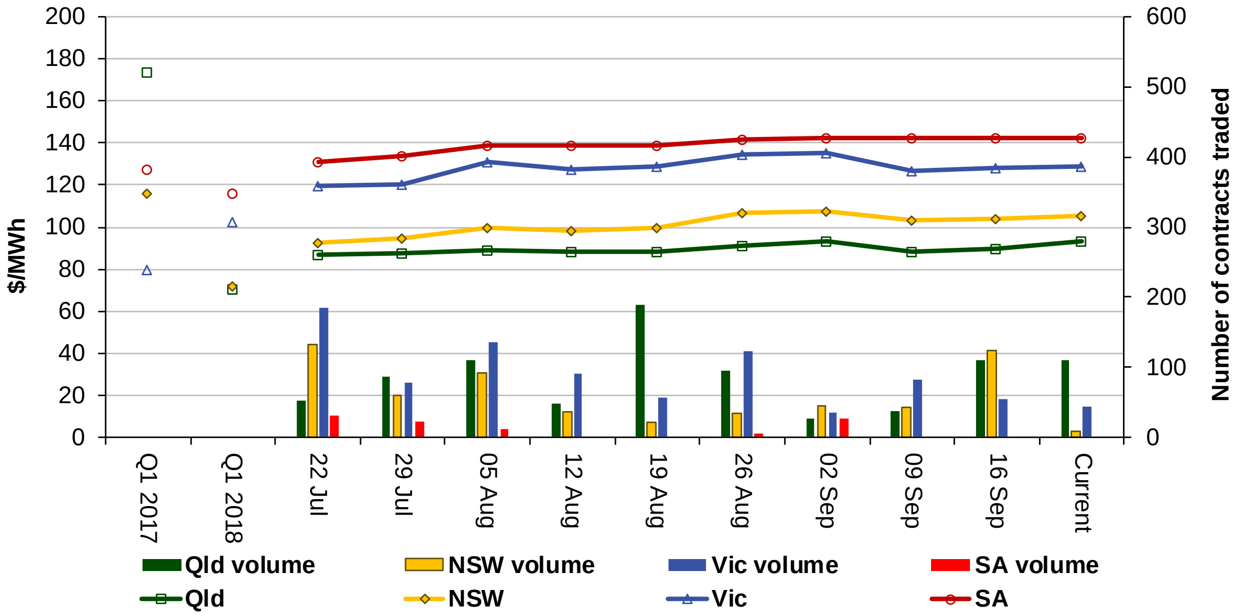
Figure 9: Quarterly base future prices Q3 2018 – Q2 2022



Source. ASXEnergy.com.au

Figure 10 shows how the price for each regional Q1 2019 base contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing quarter 1 2017 and quarter 1 2018 prices are also shown. The AER notes that data for South Australia is less reliable due to very low numbers of trades.

Figure 10: Price of Q1 2019 base contracts over the past 10 weeks (and the past 2 years)



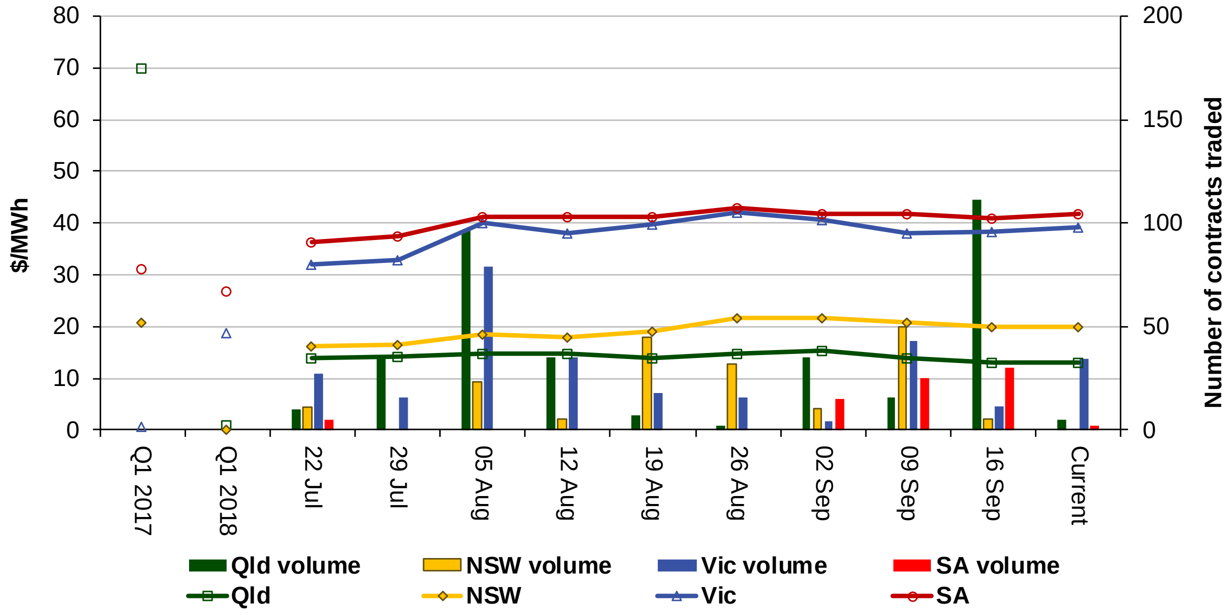
Note. Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for periods 1 and 2 years prior to the current year.

Source. ASXEnergy.com.au

Prices of other financial products (including longer-term price trends) are available in the [Industry Statistics](#) section of our website.

Figure 11 shows how the price for each regional quarter 1 2019 cap contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing quarter 1 2017 and quarter 1 2018 prices are also shown.

Figure 11: Price of Q1 2019 cap contracts over the past 10 weeks (and the past 2 years)



Source. ASXEnergy.com.au

Australian Energy Regulator
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